United States Department of the Interior

NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
Denver, CO 80225

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IN REPLY REFER TO:

May 10, 2010

N3615 (2350)

Terry L. O'Clair, P.E., Director
Division of Air Quality
North Dakota Department of Health
Environmental Health Section
918 E. Divide Ave., 2nd Floor
Bismarck, North Dakota 58501-1947

Dear ~~Mr. O'Clair~~ Terry:

As requested in your recent Public Notice, the National Park Service (NPS) is submitting the enclosed comments regarding the proposed Best Available Control Technology (BACT) determinations for the Milton R. Young Station (MRYS) near Center, North Dakota. MRYS is located within 300 km of two Class I areas, Lostwood National Wildlife Refuge administered by the U.S. Fish & Wildlife Service and Theodore Roosevelt National Park administered by the NPS. Our comments include appendices regarding baseline emissions and costs of adding Selective Catalytic Reduction (SCR) at MRYS. We conclude that SCR is technically and economically feasible at MRYS and should be determined to be BACT for that facility, thereby minimizing the impacts of MRYS at these Class I areas.

We look forward to working with the North Dakota Department of Health and with EPA as this process advances. We believe that good communication and sharing of information will help expedite this process, and suggest that you contact Don Shepherd of my staff (don_shepherd@nps.gov, 303-969-2075) if you have any questions or comments.

Sincerely,

John Bunyak

John Bunyak
Chief, Policy, Planning and Permit Review Branch

Enclosures

cc:
Callie Videtich
Air Technical Assistance Unit (8P-AR)
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NPS Comments on NDDH Best Available Control Technology Determination For Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2 May 10, 2010

Background

Minnkota Power Cooperative, Inc. (Minnkota) operates the Milton R. Young Station (MRYS) near Center, North Dakota. MRYS is a steam electric generating plant with two units. Unit #1 is a Babcock & Wilcox (B&W) cyclone-type coal-fired boiler burning lignite coal, serving a turbine generator with a nameplate rating of 257 MW. Particulate control is provided by a Research-Cottrell Electrostatic Precipitator rated at approximately 99% control. Unit #1 has no sulfur dioxide (SO_2) control system and exhausts to a 300 foot tall stack. Unit # 2 is a B&W cyclone-fired unit burning lignite coal, with a turbine-generator nameplate rating of 477 MW. Particulate control for Unit #2 is provided by a Wheelabrator-Lurgi precipitator rated at approximately 99% control. Unit #2 has a Combustion Equipment Associates wet flue gas desulfurization (FGD) system (modified by Combustion Engineering) that treats approximately 78% of the flue gas with the remaining flue gas by-passed for stack gas reheat. The FGD system achieves approximately 75% SO_2 removal and exhausts to a 550 foot tall stack. Unit #1 began commercial operation on November 20, 1970 and Unit #2 on May 11, 1977.

On 17 June 2002, Minnkota received a Notice of Violation (NOV) from EPA stating that Minnkota allegedly violated the Prevention of Significant Deterioration (PSD) regulations. The NOV was issued pursuant to Section 113 of the Clean Air Act. The alleged violation was caused by modifications to both Unit #1 and #2 at MRYS which allegedly resulted in a potential increase of SO_2, NO_X and PM. Without an admission of liability, Minnkota entered into a settlement in the form of a Consent Decree (CD) with the EPA and the North Dakota Department of Health (NDDH) to resolve the issues. The CD requires that Minnkota install a level of control for SO_2, NO_X[1] and PM on both Unit #1 and #2 at MRYS, equivalent to Best Available Control Technology (BACT).[2]

Best Available Control Technology (BACT) Review

EPA's New Source Review Workshop Manual (NSR Manual) outlines five basic steps that are to be followed in this BACT analysis. These basic steps for such a BACT analysis are summarized as follows:

Step 1 – Identify All Control Technologies
Step 2 – Eliminate Technically Infeasible Options
Step 3 – Rank Remaining Control Technologies by Control Effectiveness
Step 4 – Evaluate Most Effective Controls and Document Results
Step 5 – Select BACT

Following are our comments on application of the five steps by Minnkota and NDDH.

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[1] The Consent Decree requires Minnkota and Square Butte to perform a "NO_X Top-Down Best Available Control Technology (BACT) Analysis" to describe the emission limits for NO_X that will be required at Units #1 and #2, expressed as a 30-Day Rolling Average NO_X Emission Rate.

[2] The effect of the CD on the Best Available Retrofit Technology (BART) analysis and the requirement to install BACT-level controls are discussed later in the report.

Step 1 – Identify All Control Technologies
NDDH identified Low-Dust Selective Catalytic Reduction (LDSCR) and Tail-End Selective Catalytic Reduction (TESCR) as technically-feasible options. While we agree with those selections, we believe that NDDH should have considered Regenerative Selective Catalytic Reduction (RSCR) which is currently available from Babcock Power and in operation on large biomass boilers. RSCR has the potential to significantly reduce reheat expenses versus the approach evaluated by NDDH.

Step 2 – Eliminate Technically Infeasible Options
Minnkota rejected the use of steam to reheat the gas stream ahead of either SCR approach on the basis that it would reduce plant output. This is not an issue of technical feasibility—instead, Minnkota and NDDH must evaluate the economic feasibility of steam reheat.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness
NDDH adequately evaluated the effectiveness of both LDSCR and TESCR.

Step 4 – Evaluate Most Effective Controls and Document Results
As discussed in our Appendix A, "NPS Comments on Milton R. Young Station (MRYS) Baseline Emissions," we believe that Minnkota and NDDH have underestimated the amount of NO_X that would be reduced by the SCR options. For example, NDDH has estimated baseline emissions by using historic average emission data instead of upper-bound emission data as directed by the NSR Manual. NDDH compounded this error by comparing its cost-effectiveness results for lower emission rates and utilization to other permits[3] that were based upon assumptions of maximum allowable emissions at 100% utilization. The effect of this approach by NDDH is to bias the cost-effectiveness analysis toward higher values than would have been derived had NDDH used the same approach as was used for the permits it used for comparison.

As discussed in our Appendix B, "NPS Comments on Milton R. Young Station (MRYS) Unit #1 (and Unit #2) Tail-End Selective Catalytic Reduction (TESCR) Costs," we believe that Minnkota and NDDH have overestimated the costs of TESCR. We applied the EPA OAQPS Control Cost Manual (Cost Manual) approach to MRYS to estimate the cost of adding SCRs but did not include any estimates for the associated reheat systems because that information was not made available to us.[4]

Because some method must be applied to reheat the gases leaving the wet scrubber, additional equipment would be required and additional costs would be incurred. However, it was not possible from the information provided to determine how much this additional equipment would cost. Therefore, we compared the estimates presented by Minnkota to the ratios used by the Cost Manual to relate capital and some operating costs, to Total Direct Capital Cost. The Cost Manual

[3] For example, the analyses and resulting permit limits for WYGEN 3 and Dry Fork permits cited by NDDH were based upon maximum allowable emissions at 100% utilization.

[4] We are requesting information that will allow us to evaluate the costs of each major component and will then be able to apply our SCR-only cost estimates to the SCR-specific costs included in the information we are requesting.

can be applied for estimating annual operating costs and we found several differences between the Cost Manual approach and the Minnkota estimates. For example, Minnkota incorrectly included major costs for "Allowance for Funds During Construction," "Escalation" and "Owner's Costs", and added a "levelization" factor to the "Total Annual Cost", which are not allowed by the Cost Manual. Our estimates for the costs of installing and operating ASOFA plus TESCR with reheat systems are shown in the table below and explained in detail in the enclosures.

Operating company	**Basin Electric Power**	
Facility	**Milton R. Young**	
Unit	#1	#2
Rating (MW Gross)	257	477
Rating (mmBtu/hr)	3,200	6,300
Current Emissions (tpy)	12,054	23,731
Current Emission Rate (lb/mmBtu)	0.86	0.86
ASOFA		
New Emission Rate (lb/mmBtu)	0.513	0.489
New Emissions (tpy)	7,190	13,493
Capital Cost	$4,277,000	$10,008,000
Capital Cost ($/kW)	$17	$21
O&M Cost	$65,776	$159,744
Total Annual Cost	$469,494	$1,104,429
Cost-Effectiveness ($/ton)	$97	$108
TESCR		
Emissions Reduction (tpy)	6,503	12,141
Capital Cost	$180,206,747	$266,981,971
Capital Cost ($/kW)	$701	$560
O&M Cost	$7,383,763	$12,033,720
Total Annual Cost	$24,394,005	$37,234,930
Incremental Cost-Effectiveness ($/ton)	$3,751	$3,067
ASOFA+TESCR		
Control Efficiency	94%	94%
New Emission Rate (lb/mmBtu)	0.049	0.049
New Emissions (tpy)	687	1,352
Emissions Reduction (tpy)	11,367	22,379
Capital Cost	$184,483,747	$276,989,971
Capital Cost ($/kW)	$718	581
O&M Cost	$7,449,539	$12,193,465
Total Annual Cost	$24,863,500	$38,339,358
Average Cost-Effectiveness ($/ton)	$2,187	$1,713

Step 5 – Select BACT

NDDH has correctly noted that BACT determinations are typically based upon comparisons to other BACT determinations for similar sources, and that cost data on SCR determinations are relatively sparse because such cost analyses are seldom conducted for this top level of control. Of the BACT determinations summarized by NDDH in its Table 8, we have sufficient data on only the Dry Fork and WYGEN 3 projects. In those two cases, the Wyoming Department of Environmental Quality (WY DEQ) determined that Average Annual Costs of $1,511/ton and $4,037/ton, respectively, were reasonable for the combinations of combustion controls plus SCR. WY DEQ also determined that Incremental costs of $10,303 and $11,102, respectively, were reasonable for the SCR scenarios.

NDDH has also included cost data on several Best Available Retrofit Technology (BART) determinations.[5] However, because BACT is usually based upon evaluations of control technologies that have been accepted, we believe that NDDH should have primarily considered those BART determinations in which SCR was accepted. Of the sources listed by NDDH in its Table 9, only for PGE Boardman ($3,096/ton), Big Stone #1 ($825/ton), Boswell Energy Center #3 ($3,201/ton), and Healy #1 ($3,374/ton) was SCR determined to represent BART. In addition to those sources, SCR has been determined to be BART at Jim Bridger #3 & #4 ($4,262/ton each) and Naughton #3 ($2,830/ton) in Wyoming.

It can be seen from the data presented by NDDH and by NPS that, for the 12 sources where SCR was selected as BACT or BART, Average Annual Costs ranged from $825/ton - $4,262/ton, and for ten of those 12 SCR determinations, Average Annual Costs equaled or exceeded the Average Annual Costs we estimated for addition of SCR on both units at MRYS. We therefore conclude that, when compared to the costs of those SCRs accepted as BACT or BART, LDSCR and TESCR are economically feasible at MRYS and should be determined to be BACT.

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[5] MRYS Units #1 and #2 were determined to be subject to BART by the NDDH. However, prior to the completion of the BART analysis, Minnkota entered into a Consent Decree (CD) that requires the MRYS to install BACT-level controls for NO_X, SO_2, and PM. Thus, the BART analysis was reduced to an evaluation of the BACT-level control technologies and emission reductions specified by the CD. Because BACT and BART analyses have similar steps, the only remaining step for recommending BART was to perform a visibility impairment impact analysis and discern if there was an acceptable impact reduction. NPS submitted comments to NDDH on BART in October of 2009.

Appendix A. NPS Comments on Milton R. Young Station (MRYS) Baseline Emissions

Minnkota p4-3: **4.1 RANK OF NOX CONTROL OPTIONS BY EFFECTIVENESS** The first step in this supplemental "top-down" BACT evaluation is to determine the expected control effectiveness of the hypothetical application of tail end and low-dust SCR technology alternatives, so that they may be compared and ranked relative to the technically-feasible NO_X control techniques and technologies included from the initial NO_X BACT Analysis Study report. To do this, we start with the basis for determining the NO_X emissions control effectiveness, which is the historic baseline emissions expressed in pounds per million Btu of heat input from the five-year lookback period.

NPS: Use of historic baseline emissions is permissible only if they are documented and do not determine the outcome of the analysis/or constraints are enforceable, and provided that the cost-effectiveness is compared to similar sources using similar approaches. According to the NSR Workshop Manual [***emphasis added***]:

"...baseline emissions are essentially uncontrolled emissions, calculated using realistic upper boundary operating assumptions."

"...in developing a realistic upper boundary case, baseline emissions calculations can also consider inherent physical or operational constraints on the source.

Such constraints should accurately reflect the true upper boundary of the source's ability to physically operate and the ***applicant should submit documentation to verify these constraints***. If the applicant does not adequately verify these constraints, then the reviewing agency should not be compelled to consider these constraints in calculating baseline emissions. In addition, the reviewing agency may require the applicant to calculate cost effectiveness based on values exceeding the upper boundary assumptions to determine whether or not the assumptions have a deciding role in the BACT determination. ***If the assumptions have a deciding role in the BACT determination, the reviewing agency should include enforceable conditions in the permit to assure that the upper bound assumptions are not exceeded.***

In addition, historic upper bound operating data, typical for the source or industry, may be used in defining baseline emissions in evaluating the cost effectiveness of a control option for a specific source. For example, if for a source or industry, historical upper bound operations call for two shifts a day, it is not necessary to assume full time (8760 hours) operation on an annual basis in calculating baseline emissions. ***For comparing cost effectiveness, the same realistic upper boundary assumptions must, however, be used for both the source in question and other sources (or source categories) that will later be compared during the BACT analysis.***"

MRYS #1 Baseline Emissions

Minnkota p4-4: Unit 1 boiler's baseline pre-control emissions at Milton R. Young Station are based upon the same highest rolling 12-month average unit emission rate (lb/mmBtu) and corresponding highest rolling 12- month average gross heat input rate (mmBtu/hr) that were reported in 2001-2005:

- MRYS Unit 1's highest 12-month NOX mass emissions averaged 0.849 lb/mmBtu at a corresponding average unit heat input rate of 2,744 mmBtu/hr and unit gross electrical output of 244.5 MWg.
- During this lookback time period, Unit 1 at Milton R. Young Station was typically operated in a base-loaded manner.

NPS: **MRYS #1's highest annual NO_X mass emissions averaged 0.866 lb/mmBtu in 1995 and 0.843 in 2004.** MRYS #1's highest annual average unit heat input rate of 2,761 mmBtu/hr occurred in 2003. MRYS #1's highest annual availability of 97% occurred in 2001 and again in 2004.

In its 2009 BART determination, **NDDH stated that MRYS #1 had a Boiler Rating of 3,200 x 10^6 Btu/hr**, with 2000 – 2004 NO_x emissions averaging 8,665 tons/year (tpy) and 0.81 lb/mmBtu. NDDH used a baseline emission rate of 9,032 tpy. The subsequent **NDDH BART permit again stated the rated capacity as 3,200 mmBtu/hr** and limited NO_x emissions to 0.36 lb/mmBtu on a 30-day rolling average; there were no limits on annual emissions.

In its 2010 BACT determination, NDDH stated that MRYS Unit 1 had a heat input of 2,728 mmBtu/hr and 2003 – 2007 NO_x emissions averaging 9,081 tpy and 0.840 lb/mmBtu. NDDH calculated a maximum emission rate of 9,676 tpy and used a baseline emission rate of 9,934 tpy. **ASOFA would achieve 0.513 lb/mmBtu.**

According to Tom Bachmann of NDDH (4/26/10 e-mail), **"the Title V Permit to Operate limits NO_x emission from Unit 1 to 2752 lb/hr... This effectively caps annual emissions…"** to 12,054, tpy at 8760 hr/yr operation which is equivalent to 0.86 lb/mmBtu @ 3,200 mmBtu/hr @ 100% utilization. **It is clear that NDDH is using 3,200 mmBtu/hr heat input, 100% utilization, and 0.86 lb/mmBtu in conducting its BART analyses and developing its Title V permit.**

In the absence additional constraints, baseline emissions for the purpose of evaluating the cost-effectiveness of additional NO_x controls should be estimated at 0.86 lb/mmBtu and SCR cost-effectiveness should be assumed at 0.513 lb/mmBtu @ 3,200 mmBtu/hr with 100% capacity utilization.[1] This yields a baseline NO_x emission rate of 12,054 tpy for the uncontrolled situation and 7,190 tpy for the emissions into the SCR.

MRYS #2 Baseline Emissions

Minnkota p4-4: Unit 2 boiler's baseline pre-control emissions at Milton R. Young Station are based upon the same highest rolling 12-month average unit emission rate (lb/mmBtu) and corresponding highest rolling 12- month average gross heat input rate (mmBtu/hr) that were reported in 2001-2005:

• MRYS Unit 2's highest 12-month NO_X mass emissions averaged 0.786 lb/mmBtu at a corresponding average unit heat input rate of 4,885 mmBtu/hr and unit gross electrical output of 440 MW.

• During this lookback time period, Unit 2 at Milton R. Young Station was typically operated in a base-loaded manner.

NPS: **MRYS #2's highest annual NO_X mass emissions averaged 0.856 lb/mmBtu in 2007.** MRYS #2's highest annual average unit heat input rate of 5,230 mmBtu/hr occurred in 1997. MRYS #2's highest annual availability of 95% occurred in 2000 and again in 2008.

In its 2009 BART determination, **NDDH stated that MRYS #2 had a Boiler Rating of 6,300 x 10^6 Btu/hr,** with 2000 – 2004 NO_x emissions averaging 14,705 tons/year and 0.81 lb/mmBtu. NDDH used a baseline emission rate of 15,507 tpy. The subsequent **NDDH BART permit again stated the rated capacity as 6,300 mmBtu/hr** and limited NO_x emissions to 0.35 lb/mmBtu (excluding startup) on a 30-day rolling average; there were no limits on annual emissions.

In its 2010 BACT determination, NDDH stated that MRYS #2 had a heat input of 4,691 mmBtu/hr and 2003 – 2007 NO_x emissions averaging 14,858 tons/year and 0.835 lb/mmBtu. NDDH calculated a maximum emission rate of 15,818 tpy and used a baseline emission rate of 15,793 tpy. **ASOFA would achieve 0.489 lb/mmBtu.**

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[1] According to the NSR Workshop Manual, "For comparing cost effectiveness, the same realistic upper boundary assumptions must, however, be used for both the source in question and other sources (or source categories) that will later be compared during the BACT analysis." In its Table 8, NDDH has used cost-effectiveness data from permits issued by Wyoming to Basin Electric for its Dry Fork PC boiler and to Black Hills Power for its Wygen 3 PC boiler. Because both of those cost-effectiveness analyses were based upon 100% utilization of the PC boilers, NDDH must use the same 100% capacity utilization for comparison to MR Young. (At 97% availability, the historic maximum availability for MRYS #1, the baseline NO_x emission rates would be 11,704 tpy for the uncontrolled situation and 6,982 tpy for the emissions into the SCR.)

According to Tom Bachmann of NDDH (4/26/10 e-mail), **"the Title V Permit to Operate limits NO_x emission…to…5418 lb/hr from Unit 2. This effectively caps annual emissions…"** to 23,731, tpy at 8760 hr/yr operation which is equivalent to 0.86 lb/mmBtu @ 6,300 mmBtu/hr @ 100% utilization. **It is clear that NDDH is using 6,300 mmBtu/hr heat input, 100% utilization, and 0.86 lb/mmBtu in conducting its BART analyses and developing its Title V permit.**

In the absence additional constraints, baseline emissions for the purpose of evaluating the cost-effectiveness of additional NO_x controls should be estimated at 0.86/b/mmBtu and SCR cost-effectiveness should be assumed at 0.489 lb/mmBtu @ 6,300 mmBtu/hr with 100% capacity utilization.[2] This yields a baseline NO_x emission rate of 23,731 tpy for the uncontrolled situation and 13,493 tpy for the emissions into the SCR.

[2] At 95% availability, the historic maximum availability for MRYS #2, the baseline NO_x emission rates would be 22,652 tpy for the uncontrolled situation and 12,880 tpy for the emissions into the SCR.)

Appendix B. SCR Cost Information

According to an article in the June 2009 "Power" magazine:[1]
"One more current data set is the historic capital costs reported by AEP averaged over several years and dozens of completed projects. For example, AEP reports that their historic average capital costs for SCR systems are $162/kW for 85% to 93% NO_X removal..."
"...historical data finds the installed cost of an SCR system of the 700MW-class as approximately $125/kW over 22 units with a maximum reported cost of $221/kW in 2004 dollars. This data was reported prior to the dramatic increase in commodity prices of 14% per year average experienced from 2004 to 2006 (from the FGD survey results). Applying those annual increases to the 2004 estimates for three years (from the date of the survey to the end of 2007) produces an average SCR system installed cost of $185/kW..."
"Overall, costs were reported to be in the $100 to $200/kW range for the majority of the systems, with only three reported installations exceeding $200/kW."

Five industry studies conducted between 2002 and 2007 have reported the installed unit capital cost of SCRs, or the costs actually incurred by owners, expressed in dollars per kilowatt.

The first study evaluated the installed costs of more than 20 SCR retrofits from 1999 to 2001. The installed capital cost ranged from $106 to $213/kW, converted to 2007 dollars.[2] Costs are escalated through using the Chemical Engineering Plant Cost Index ("CEPCI").
The second survey of 40 installations at 24 stations reported a cost range of $76 to $242/kW, converted to 2007 dollars.[3]
The third study, by the Electric Utility Cost Group, surveyed 72 units totaling 41 GW, or 39% of installed SCR systems in the U.S. This study reported a cost range of $118/kW to $261/kW, converted to 2007 dollars.[4]
A fourth study, presented in a course at PowerGen 2005, reported an upper bound range of $180/kW to $202/kW, converted to 2007 dollars.[5]

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[1] June 13, 2009 "Power" magazine article "Air Quality Compliance: Latest Costs for SO2 and NOx Removal (effective coal clean-up has a higher–but known–price tag)" *by* Robert Peltier. http://www.masterresource.org/2009/06/air-quality-compliance-latest-costs-for-so2-and-nox-removal-effective-coal-clean-up-has-a-higher-but-known-price-tag/

[2] Bill Hoskins, Uniqueness of SCR Retrofits Translates into Broad Cost Variations, Power Engineering, May 2003. Ex. 2. The reported range of $80 to $160/kW $123 - $246/kW was converted to 2008 dollars ($116 - $233/kW) using the ratio of CEPCI in 2008 to 2002: 575.4/395.6.

[3] J. Edward Cichanowicz, Why are SCR Costs Still Rising?, Power, April 2004, Ex. 3; Jerry Burkett, Readers Talk Back, Power, August 2004, Ex. 4. The reported range of $56/kW - $185/kW was converted to 2008 dollars ($83 - $265/kw)using the ratio of CEPCI for 2008 to 1999 (575.4/.390.6) for lower end of the range and 2008 to 2003 (575.4/401.7) for upper end of range, based on Figure 3.

[4] M. Marano, Estimating SCR Installation Costs, Power, January/February 2006. Ex. 5. The reported range of $100 - $221/kW was converted to 2008 dollars ($130 - $286/kW) using the ratio of CEPCI for 2008 to 2004: 575.4/444,2. http://findarticles.com/p/articles/mi_qa5392/is_200602/ai_n21409717/print?tag=artBody;col1

[5] PowerGen 2005, Selective Catalytic Reduction: From Planning to Operation, Competitive Power College, by Babcock Power, Inc. and LG&E Energy, December 2005, Ex. 6. The reported range of $160 - $180/kW) was converted to 2008 dollars ($197 - $221/kW) using the ratio of CEPCI for 2008 to 2005 (575.4/468.2).

A fifth summary study, focused on recent applications that become operational in 2006 or were scheduled to start up in 2007 or 2008, reported costs in excess of \$200/kW on a routine basis, with the highest application slated for startup in 2009 at \$300/kW.[6]

Thus, the overall range for these industry studies is \$50/kW to \$300/kW. The upper end of this range is for highly complex retrofits with severe space constraints, such as Belews Creek, reported to cost \$265/kW,[7] or Cinergy's Gibson Units 2-4. Gibson, a highly complex, space-constrained retrofit in which the SCR was built 230 feet above the power station using the largest crane in the world,[8] only cost \$251/kW in 2007 dollars.[9]

[6] J. Edward Cichanowicz, Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies, June 2007, pp. 28-29, Figure 7-1 (Ex. 1).

[7] Steve Blankinship, SCR = Supremely Complex Retrofit, Power Engineering, November 2002, Ex. 7. The unit cost: (\$325,000,000/1,120,000 kW)(608.8/395.6) = \$290/kW. http://pepei.pennnet.com/display_article/162367/6/ARTCL/none/none/1/SCR-=-Supremely-Complex-Retrofit/

[8] Standing on the Shoulder of Giants, Modern Power Systems, July 2002, Ex. 8.

[9] McIlvaine, NOX Market Update, August 2004, Ex. 9. SCR was retrofit on Gibson Units 2-4 in 2002 and 2003 at \$179/kW. Assuming 2002 dollars, this escalates to (\$179/kW)(608.8/395.6) = \$275.5/kW. http://www.mcilvainecompany.com/sampleupdates/NoxMarketUpdateSample.htm

Appendix B. NPS Comments on Milton R. Young Station (MRYS) Unit #1 Tail-End Selective Catalytic Reduction (TESCR) Costs

As discussed in Appendix B, recent industry literature suggests that most SCR retrofits can be accomplished at a Total Capital Investment (TCI) under $200/kW, with the average cost at about $185/kW. We have found that the OAQPS Control Cost Manual (Cost Manual) tends to produce much lower estimates for TCI. In order to allow one to "adjust" the Cost Manual approach to produce TCI estimates more comparable to the industry literature, we have added "extra[1] retrofit" factors to adjust both the Direct Capital Cost (DCC) and the Indirect Capital Cost. These extra retrofit factors also allow us to account for unusual retrofit situations. In this case, we assumed extra retrofit factors that yielded a TCI of $185/kW for the addition of SCR (with bypass, or $179/kW without bypass). Because this is consistent with the industry estimates, we believe this to be a reasonable estimate of TCI for the SCR portion of this project. Following is a detailed discussion of selected individual elements of the cost analysis.

Baseline Emissions

The EPA New Source Review Workshop Manual (NSR Manual) states that "...baseline emissions are essentially uncontrolled emissions, **calculated using realistic upper boundary operating assumptions**." (emphasis added) The enclosed document "NPS Comments on Milton R. Young Station (MRYS) Baseline Emissions" describes our rationale for determining the following "upper boundary baseline emissions" for MRYS #1 instead of the average values used by Minnkota and NDDH:

- **Heat input = 3,200 mmBtu/hr** stated in NDDH BART analyses. NDDH used 2,728 in its BACT analysis which appears to represent a historic two-year average and not a historic annual upper bound.
- **Utilization = 100%** from NDDH underlying assumptions in their BART analyses and resulting Title V permit. Instead, NDDH used 96.4% in its BACT analysis which appears to represent a historic two-year average and not a historic annual upper bound.
- **Uncontrolled NOx Concentration (lb/mmBtu) = 0.86** because this is consistent with the MRYS #1 Title V permit and MRYS Unit 1's highest annual NO_X mass emissions averaged 0.866 lb/mmBtu in 1995 and NDDH used 0.86 lb/mmBtu in its BART analysis. NDDH used 0.840 lb/mmBtu in its BACT analysis which appears to represent a historic two-year average and not a historic annual upper bound.

[1] The Cost Manual approach already includes an estimate for additional retrofit costs.

Given Information, Assumptions, and Direct Capital Costs

We applied the Cost Manual approach to MRYS #1 to estimate the cost of adding SCR **but did not include any estimates for the associated reheat systems because that information was not made available to us.**[2] Following is a discussion and comparison of specific combustion control (Advanced Separated Over-Fire Air = ASOFA) plus stand-alone tail-end SCR (TESCR) cost items that warrant explanation:

- ASOFA Annualized Capital Cost = \$403,719 based upon \$4,277,000 DCC amortized over a 20-year life @ 7% interest (Cost Manual).
- ASOFA Annual O&M Cost (not levelized) = \$65,776 calculated from company BACT analysis **minus the \$1,631,000 lost generation cost**[3] and adjusted to 100% availability.
- **ASOFA Total Annual Cost = \$469,494**. NDDH estimated \$2,489,000/yr. The differences are primarily due to the unsupported cost of lost generation and the application of an improper levelization factor.
- Fuel Sulfur Content was held at the pre-scrubbed value but would effectively decrease for a TESCR and yield a smaller SCR.
- 29% Ammonia Solution Cost (\$/lb) was taken from the BART analyses conducted by PacifiCorp in Wyoming because Minnkota chose urea as the SCR reagent, primarily for safety reasons. However, according to the Institute of Clean Air Companies,[4] "With the proper controls, ammonia use is safe and routine."
- **Catalyst Cost (\$/m^3) = \$3,000** was taken from the BART analyses conducted by PacifiCorp in Wyoming because the Minnkota/Burns & McDonnell estimate of \$7,500/m^3 was much higher than the \$3,000 - \$6,000/m^3 we typically see from other consultants.
- **Operating Life of Catalyst (hours) = 16,000** which appears to be the consensus estimate from the catalyst vendors.
- **Natural gas unit cost (\$/mcf) = \$5** based upon current prices according to EIA.
- Natural gas for reheat (mcf) = 460,090 mcf (from Minnkota) and does not include NG to vaporize urea because ammonia is used in this scenario.

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[2] We are requesting information that will allow us to evaluate the costs of each major component and will then be able to apply our SCR-only cost estimates to the SCR-specific costs included in the information we are requesting.

[3] Minnkota estimated that retrofitting of ASOFA would result in 181 hr/yr of lost operating time due to maintenance of ASOFA, and that Unit 2 operation would drop to 8,048 hr/yr as a result. Minnkota installed ASOFA on Unit #2 in 2007 and availability increased from the pre-ASOFA 89% (7,792 hr/yr) average to the post-ASOFA 95% (8,256hr/yr).

[4] May 2009 Institute of Clean Air Companies white paper titled "Selective Catalytic Reduction (SCR) Control of NO_x Emissions from Fossil Fuel-Fired Electric Power Plants"*Can Ammonia Be Handled Safely?* Yes. Concern over the handling of ammonia was initially raised as a problem with SCR technology applications due to the transportation and storage of a hazardous gas under pressure. However, large quantities of ammonia already are used for a variety of applications with an excellent overall safety record. (In 200 6, 17 billion pounds of ammonia were produced in t he U.S.) These applications include the manufacture of fertilizers and a variety of other chemicals, as well as refrigeration. With the proper controls, ammonia use is safe and routine.

- **Volcatalyst = 634 m^3 for one reactor.** The Cost Manual approach results in the reactor having four layers of catalyst plus one spare layer. Minnkota estimated three layers plus one spare with catalyst volume at 633 m^3.
- **Direct Capital Cost (DCC), A = $14 million before adjustments and $29 million with adjustments. Minnkota estimates** DCC = $127 million for SCR plus ASOFA and the associated reheat equipment. Subtracting the $4 million DCC cost of ASOFA results in **DCC = $123 million for SCR plus the associated reheat equipment.** We would like to see the separate cost estimates developed by Minnkota for the SCR as well as the reheat system so that we could directly compare our SCR cost estimate.

Total Capital Investment

The next portion of our cost analysis will assume that Minnkota has properly estimated its Direct Capital Costs for SCR plus the associated reheat equipment. We will also assume that the ratios of Indirect Capital Costs (ICC) to Direct Capital Costs (DCC) used by the Cost Manual for stand-alone SCR also apply to the complete SCR plus reheat "package" evaluated by Minnkota.[5] Our SCR-only costs are estimated on the "ICC" tab of the associated Excel workbook. Our evaluation of the Minnkota SCR+reheat system costs are shown on the "ICC (2)" tab.

- Total Indirect Installation Costs (TIIC), B = $9 million; this is 30% of DCC (because of our extra retrofit factor—instead, the Cost Manual estimates TIIC = 20% of DCC.) **Minnkota estimates TIIC = $45 million** for SCR plus associated equipment; this is 37% of Minnkota's $123 million DCC and appears excessive when compared to the 20% ratio used by the Cost Manual. **A more appropriate value for TIIC would be $25 million.**
- Project Contingency, C = $9 million; this is 29% of (DCC+TIIC). (The Cost manual estimates TIIC = 18% of (DCC+TIIC).) **Minnkota estimates Project Contingency = $20 million** for SCR plus associated equipment; this is 16% of (DCC = $127 million + adjusted TIIC = 25 million). **A more appropriate value for Project Contingency would be $22 million.**
- Total Plant Cost (TPC), D = $46 million = our estimate is 159% of the DCC upon which it is based. However, the Cost Manual ratio (without extra retrofit factors) is TPC = 138% of DCC. **Minnkota estimates TPC = $188 million** for SCR plus associated equipment; this is 153% of DCC a nd appears excessive. **A more appropriate value for TPC would be $170 million.**
- Allowance for Funds During Construction (AFDC), E = $0. **Minnkota estimates AFDC = $27 million for SCR plus associated equipment; this is not allowed by the Cost Manual.**
- Total Capital Investment (TCI = D+G+H) = $47 million for SCR; this is 163% of the DCC upon which it is based. However, the Cost Manual ratio (without extra retrofit factors) is TPC = 146% of DCC. **Minnkota estimates TCI = $290 million for SCR plus reheat equipment**; this is 236% of DCC. In addition to overestimates and the invalid $27 million for AFDC noted above, **Minnkota has**

[5] Minnkota appears to have used a similar approach.

included \$42 million for "Escalation" and \$26 million for "Owner's Costs" which are not allowed by the Cost Manual. Adjusting for these unsupported costs and applying the Cost Manual 146% ratio to the \$123 million DCC, the resulting TCI for TESCR on MRYS #1 becomes \$180 million (\$701/kW).

Annual Costs & Cost-effectiveness

We believe that the Cost Manual approach is directly applicable and appropriate to estimate annual costs of the stand-alone SCR ("Ann Cost" tab) and of the entire Minnkota SCR+reheat system ("Ann Cost (2) tab) using the corrected TCI derived above. The following discussion describes the cost estimates in the "Ann Cost (2)" tab.

- Annual Maintenance Cost = 1.5% of TCI (= \$47 million). Minnkota has incorrectly assumed 3% of TCI to estimate \$7 million. If we assume that Annual Maintenance Cost = 1.5% of the \$180 million TCI for TESCR derived above, then **we estimate \$3 million.**
- **Annual Reagent Cost = \$1 million for ammonia.** Minnkota estimates \$3 million for urea.
- **Annual Electricity Cost = \$0.5 million.** Minnkota estimates \$6 million, primarily due to "lost generation."
- Annual Catalyst Cost = \$1 million. Minnkota estimates \$1 million.
- **Annual natural gas Cost = \$2 million.** Minnkota estimates \$4 million, primarily due to use of NG to vaporize urea and a higher unit gas price.
- Direct Annual Cost (DAC) = \$7 million and is the sum of the individual annual costs using our estimates modified to reflect a TCI of \$180 million. (See the "Annual Cost (2)" tab. Minnkota estimated \$20 million.
- Indirect Annual Cost = \$17 million based a TCI of \$180 million.
- **Total Annual Cost (TAC) = \$25 million** for ASOFA+SCR plus reheat equipment based a TCI of \$180 million (for ASOFA+SCR plus reheat equipment); Minnkota estimates TAC = \$44 million and includes an improper "levlization" factor to escalate cost.
- **SCR Cost-effectiveness to remove 6,503 tpy of NO_X is = \$3,800/ton.**
- **Total Cost-effectiveness to remove 11,367 tpy of NO_X is = \$2,200/ton. NDDH estimates \$4,615/ton**

Results & Conclusions

Based upon the approach recommended by the Cost Manual, our estimate for the cost of adding only the ASOFA and SCR components of a Tail-End SCR (TESCR) system to MRYS #1 is a Total Capital Investment of \$52 million (\$201/kW) and a Total Annual Cost of \$8 million. Using upper bound emission estimates, as recommended by the NSR Manual, combined with NDDH estimates of controlled emissions, we estimate that ASOFA + TESCR could reduce NO_X emissions by **11,367 tpy** (**6,503 tpy** by the SCR alone). The Average Cost-Effectiveness for the ASOFA + TESCR system would be \$700/ton and addition of the TESCR has a cost-effectiveness of \$1,200/ton.

Because some method must be applied to reheat the gases leaving the wet scrubber, additional equipment would be required and additional costs would be incurred. It was not possible from the information provided to determine how much this additional equipment cost. Therefore, we compared the estimates presented by Minnkota to the ratios used by the Cost Manual to relate capital and some operating costs to Total Direct Capital Cost. Minnkota incorrectly included major costs for "Allowance for Funds During Construction," "Escalation" and "Owner's Costs" which are not allowed by the Cost Manual. Adjusting for these unsupported costs, the resulting Total Capital Investment for TESCR on MRYS #1 becomes $180 million ($701/kW) versus the Minnkota estimate of $295 million.

The Cost Manual can be applied for estimation of annual operating costs and we found several differences between the Cost Manual approach and the Minnkota estimates. Our corrected Direct Annual Cost estimate is $7 million versus the Minnkota estimate of $20 million; the major differences are costs for "Lost Generation" and "Maintenance." Our estimated Total Annual Cost (TAC) is $25 million. Minnkota estimates TAC = $44 million. Our estimate of the Average Cost-Effectiveness for the complete ASOFA + TESCR + reheat system would be $2,200/ton and addition of the TESCR has a cost-effectiveness of $3,800/ton.

Appendix B. NPS Comments on Milton R. Young Station (MRYS) Unit #2 Tail-End Selective Catalytic Reduction (TESCR) Costs

As discussed in Appendix B, recent industry literature suggests that most SCR retrofits can be accomplished at a Total Capital Investment (TCI) under $200/kW, with the average cost at about $185/kW. We have found that the OAQPS Control Cost Manual (Cost Manual) tends to produce much lower estimates for TCI. In order to allow one to "adjust" the Cost Manual approach to produce TCI estimates more comparable to the industry literature, we have added "extra[1] retrofit" factors to adjust both the Direct Capital Cost (DCC) and the Indirect Capital Cost. These extra retrofit factors also allow us to account for unusual retrofit situations. In this case, we assumed extra retrofit factors that yielded a TCI of $192/kW for the addition of SCR (with bypass, or $187/kW without bypass). Because this is consistent with the industry estimates, we believe this to be a reasonable estimate of TCI for the SCR portion of this project. Following is a detailed discussion of selected individual elements of the cost analysis.

Baseline Emissions

The EPA New Source Review Workshop Manual (NSR Manual) states that "...baseline emissions are essentially uncontrolled emissions, **calculated using realistic upper boundary operating assumptions**." (emphasis added) The enclosed document "NPS Comments on Milton R. Young Station (MRYS) Baseline Emissions" describes our rationale for determining the following "upper boundary baseline emissions" for MRYS #1 instead of the average values used by Minnkota and NDDH:

- **Heat input = 6,300 mmBtu/hr** stated in NDDH BART analyses. NDDH used 4,691 in its BACT analysis which appears to represent a historic two-year average and not a historic annual upper bound.
- **Utilization = 100%** from NDDH underlying assumptions in their BART analyses and resulting Title V permit. Instead, NDDH used 92.2% in its BACT analysis which appears to represent a historic two-year average and not a historic annual upper bound.
- **Uncontrolled NOx Concentration (lb/mmBtu) = 0.86** because this is consistent with the MRYS #2 Title V permit and MRYS #2's highest annual NO_X mass emissions averaged 0.856 lb/mmBtu in 2007 and NDDH used 0.86 lb/mmBtu in its BART analysis. NDDH used 0.835 lb/mmBtu in its BACT analysis which appears to represent a historic two-year average and not a historic annual upper bound.

[1] The Cost Manual approach already includes an estimate for additional retrofit costs.

Given Information, Assumptions, and Direct Capital Costs

We applied the Cost Manual approach to MRYS #2 to estimate the cost of adding SCR **but did not include any estimates for the associated reheat systems because that information was not made available to us.**[2] Following is a discussion and comparison of specific combustion control (Advanced Separated Over-Fire Air = ASOFA) plus stand-alone tail-end SCR (TESCR) cost items that warrant explanation:

- ASOFA Annualized Capital Cost = $944,684 based upon $10,008,000 DCC amortized over a 20-year life @ 7% interest (Cost Manual).
- ASOFA Annual O&M Cost (not levelized) = $159,744 calculated from company BACT analysis **minus the $2,65,000 lost generation cost**[3] and adjusted to 100% availability.
- **ASOFA Total Annual Cost = $1,104,429.** Minnkota estimated $4,376,000/yr. The differences are primarily due to the unsupported cost of lost generation and the application of an improper levelization factor.
- Fuel Sulfur Content was held at the pre-scrubbed value but would effectively decrease for a TESCR and yield a smaller SCR.
- 29% Ammonia Solution Cost ($/lb) was taken from the BART analyses conducted by PacifiCorp in Wyoming because Minnkota chose urea as the SCR reagent, primarily for safety reasons. However, according to the Institute of Clean Air Companies,[4] "With the proper controls, ammonia use is safe and routine."
- **Catalyst Cost ($/m^3) = $3,000** was taken from the BART analyses conducted by PacifiCorp in Wyoming because the Minnkota/Burns & McDonnell estimate of $7,500/m^3 was much higher than the $3,000 - $6,000/m^3 we typically see from other consultants.
- **Operating Life of Catalyst (hours) = 16,000** which appears to be the consensus estimate from the catalyst vendors.
- **Natural gas unit cost ($/mcf) = $5** based upon current prices according to EIA.
- Natural gas for reheat (mcf) = 754,563 mcf (from Minnkota) and does not include NG to vaporize urea because ammonia is used in this scenario.

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[2] We are requesting information that will allow us to evaluate the costs of each major component and will then be able to apply our SCR-only cost estimates to the SCR-specific costs included in the information we are requesting.

[3] Minnkota estimated that retrofitting of ASOFA would result in 181 hr/yr of lost operating time due to maintenance of ASOFA, and that Unit 2 operation would drop to 8,048 hr/yr as a result. Minnkota installed ASOFA on Unit #2 in 2007 and availability increased from the pre-ASOFA 89% (7,792 hr/yr) average to the post-ASOFA 95% (8,256hr/yr).

[4] May 2009 Institute of Clean Air Companies white paper titled "Selective Catalytic Reduction (SCR) Control of NO_x Emissions from Fossil Fuel-Fired Electric Power Plants"*Can Ammonia Be Handled Safely?* Yes. Concern over the handling of ammonia was initially raised as a problem with SCR technology applications due to the transportation and storage of a hazardous gas under pressure. However, large quantities of ammonia already are used for a variety of applications with an excellent overall safety record. (In 2006, 17 billion pounds of ammonia were produced in the U.S.) These applications include the manufacture of fertilizers and a variety of other chemicals, as well as refrigeration. With the proper controls, ammonia use is safe and routine.

- **Volcatalyst = 617 m^3 each of two reactors.** The Cost Manual approach results in each reactor having one layer of catalyst plus one spare layer. The SCR vendor info assumed two layers plus one spare. Fuel Tech estimated catalyst volume at 249 m^3/reactor for MRYS#2. CERAM estimated catalyst volume at 390 m^3/reactor for MRYS#2. Minnkota estimated three layers plus one spare with catalyst volume at 1110 m^3/reactor.
- **Direct Capital Cost (DCC), A = $22 million before adjustments and $44 million with adjustments. Minnkota estimates** DCC = $200 million for SCR plus ASOFA and the associated reheat equipment. Subtracting the $10 million DCC cost of ASOFA results in **DCC = $190 million for SCR plus the associated reheat equipment.** We would like to see the separate cost estimates developed by Minnkota for the SCR as well as the reheat system so that we could directly compare our SCR cost estimate.

Total Capital Investment

The next portion of our cost analysis will assume that Minnkota has properly estimated its Direct Capital Costs for SCR plus the associated reheat equipment. We will also assume that the ratios of Indirect Capital Costs (ICC) to Direct Capital Costs (DCC) used by the Cost Manual for stand-alone SCR also apply to the complete SCR plus reheat "package" evaluated by Minnkota.[5] Our SCR-only costs are estimated on the "ICC" tab of the associated Excel workbook. Our evaluation of the Minnkota SCR+reheat system costs are shown on the "ICC (2)" tab.

- Total Indirect Installation Costs (TIIC), B = $18 million; this is 40% of DCC (because of our extra retrofit factor—instead, the Cost Manual estimates TIIC = 20% of DCC.) **Minnkota estimates TIIC = $70 million** for SCR plus associated equipment; this is 37% of Minnkota's $190 million DCC and appears excessive when compared to the 20% ratio used by the Cost Manual. **A more appropriate value for TIIC would be $38 million.**
- Project Contingency, C = $18 million; this is 42% of (DCC+TIIC). (The Cost manual estimates TIIC = 18% of (DCC+TIIC).) **Minnkota estimates Project Contingency = $30 million** for SCR plus associated equipment; this is 16% of (DCC = $190 million + adjusted TIIC = 38 million) **and appears reasonable.**
- Total Plant Cost (TPC), D = $80 million = our estimate is 182% of the DCC upon which it is based. However, the Cost Manual ratio (without extra retrofit factors) is TPC = 138% of DCC. **Minnkota estimates TPC = $290 million** for SCR plus associated equipment; this is 153% of DCC and appears excessive. **A more appropriate value for TPC would be $262 million.**
- Allowance for Funds During Construction (AFDC), E = $0. **Minnkota estimates AFDC = $41 million for SCR plus associated equipment; this is not allowed by the Cost Manual.**

[5] Minnkota appears to have used a similar approach.

- Total Capital Investment (TCI = D+G+H) = $82 million for SCR; this is 186% of the DCC upon which it is based. However, the Cost Manual ratio (without extra retrofit factors) is TPC = 146% of DCC. **Minnkota estimates TCI = $426 million for SCR plus reheat equipment**; this is 225% of DCC. In addition to overestimates and the invalid $41 million for AFDC noted above, **Minnkota has included $55 million for "Escalation" and $33 million for "Owner's Costs" which are not allowed by the Cost Manual. Adjusting for these unsupported costs and applying the Cost Manual 141% ratio to the $190 million DCC, the resulting TCI for TESCR on MRYS #2 becomes $267 million ($560/kW).**

Annual Costs & Cost-effectiveness

We believe that the Cost Manual approach is directly applicable and appropriate to estimate annual costs of the stand-alone SCR ("Ann Cost" tab) and of the entire Minnkota SCR+reheat system ("Ann Cost (2) tab) using the corrected TCI derived above. The following discussion describes the cost estimates in the "Ann Cost (2)" tab.

- Annual Maintenance Cost = 1.5% of TCI (= $267 million). Minnkota has incorrectly assumed 3% of TCI to estimate $10 million. If we assume that Annual Maintenance Cost = 1.5% of the $267 million TCI for TESCR derived above, then **we estimate $4 million.**
- **Annual Reagent Cost = $2 million for ammonia.** Minnkota estimates $4 million for urea.
- **Annual Electricity Cost = $1 million.** Minnkota estimates $10 million, primarily due to "lost generation."
- **Annual Catalyst Cost = $2 million.** Minnkota estimates $1 million.
- **Annual natural gas Cost = $4 million.** Minnkota estimates $6 million, primarily due to use of NG to vaporize urea and a higher unit gas price.
- Direct Annual Cost (DAC) = $12 million and is the sum of the individual annual costs using our estimates modified to reflect a TCI of $267 million. (See the "Annual Cost (2)" tab. Minnkota estimated $32 million.
- Indirect Annual Cost = $25 million based a TCI of $267 million.
- **Total Annual Cost (TAC) = $38 million** for ASOFA+SCR plus reheat equipment based a TCI of $277 million (for ASOFA+SCR plus reheat equipment); Minnkota estimates TAC = $69 million and includes an improper "levlization" factor to escalate cost.
- **SCR Cost-effectiveness to remove 12,141 tpy of NO_X is = $3,100/ton.**
- **Total Cost-effectiveness to remove 22,379 tpy of NO_X is = $1,700/ton. NDDH estimates $4,772/ton**

Results & Conclusions

Based upon the approach recommended by the Cost Manual, our estimate for the cost of adding only the ASOFA and SCR components of a Tail-End SCR (TESCR) system to MRYS #2 is a Total Capital Investment of $92 million ($192/kW) and a Total Annual Cost of $18 million. Using upper bound emission estimates, as recommended by the NSR Manual, combined with NDDH estimates of controlled emissions, we estimate that ASOFA + TESCR could reduce NO_X emissions by **22,379 tpy** (**12,141 tpy** by the SCR alone). The Average Cost-Effectiveness for the ASOFA + TESCR system would be $800/ton and addition of the TESCR has a cost-effectiveness of $1,400/ton.

Because some method must be applied to reheat the gases leaving the wet scrubber, additional equipment would be required and additional costs would be incurred. It was not possible from the information provided to determine how much this additional equipment cost. Therefore, we compared the estimates presented by Minnkota to the ratios used by the Cost Manual to relate capital and some operating costs to Total Direct Capital Cost. Minnkota incorrectly included major costs for "Allowance for Funds During Construction," "Escalation", "Owner's Costs" which are not allowed by the Cost Manual. Adjusting for these unsupported costs, the resulting Total Capital Investment for TESCR on MRYS #2 becomes $266 million ($560/kW) versus the Minnkota estimate of $426 million.

The Cost Manual can be applied for estimation of annual operating costs and we found several differences between the Cost Manual approach and the Minnkota estimates. Our corrected Direct Annual Cost estimate is $12 million versus the Minnkota estimate of $32 million; the major differences are costs for "Lost Generation" and "Maintenance." Our estimated Total Annual Cost (TAC) is $38 million. Minnkota estimates TAC = $69 million. Our estimate of the Average Cost-Effectiveness for the complete ASOFA + TESCR + reheat system would be $1,700/ton and addition of the TESCR has a cost-effectiveness of $3,100/ton.

Appendix B. SCR Cost Survey Results

Discussion of OAQPS Cost Manual Method for AQCS Estimation

submitted to the NM Environment Department by Public Service of NM regarding BART for the San Juan Generating Station
http://www.nmenv.state.nm.us/aqb/reghaz/documents/03292008DiscussionofOAQPSCostManualMethodRev080329.pdf

SCR Capital Cost Survey Results

from Table 7-1. of CURRENT CAPITAL COST AND COST-EFFECTIVENESS OF POWER PLANT EMISSION CONTROL
Prepared by J. Edward Cichanowicz for Utility Air Regulatory Group, June, 2007

Reference	Average and Low-High Cost Observations		Cost Basis
	Capital, MW ($/kW, 2006 Basis)	Observed ($/kW)	
Hoskins, 2003	128 (400 MW)	80-160	2002. 15 of 20 reported unit costs exceeded $100/kW. Weak relationship of unit cost and scale.
Cichanowicz, 2004	84 (600-899 MW) to 128 (100-399 MW)	56-185	2003. For four categories of generating capacity, the least cost units were among the first installed.
Marano, 2006	118 (>900) to 167 (<300 MW)	Most costs reported to be within 100-200	2005. "Units with a capacity of 600 to 900 MW appear to be more difficult to retrofit than those in other size ranges."

Estimation of Costs and Impacts of NOx Control Technologies Applied to the PGE Boardman Plant

http://www.deq.state.or.us/aq/haze/docs/ergMemo.pdf

Reference	Average and Low-High Cost Observations		Cost Basis
	Capital, MW ($/kW, 2006 Basis)	Observed ($/kW)	
ERG 2008	227	207 - 267	2007

Appendix B.
Milton R. Young Unit #1
OAQPS Control Cost Manual Section 4.2

Given/Assumptions

New or Retrofit?	Retrofit			
Extra Direct retrofit cost	1.5	NPS estimate		
Extra Indirect retrofit cost factor	1.5	NPS estimate		
Generation capacity (MW)	257	NDDH BART report		
SCR bypass included?	Yes	from BACT analysis		
Fuel High Heating Value (Btu/lb)	6,662	from 2006 BACT analysis		
Maximum Fuel Consumption Rate (lb/hr)	4.8E+05	calculated from	3,200	mmBtu/hr from NDDH BART report
Average Annual Fuel Consumption (lb)	4.21E+09	calculated		
Number of SCR Operating Days	365	assumed		
Plant Capacity Factor	100%	from NDDH Title V permit		
Uncontrolled NOx Concentration (lb/mmBtu)	0.86	calculated from NDDH Title V permit		
Uncontrolled NOx Emissions (tpy)	12,054	calculated from NDDH Title V permit		
ASOFA Total Capital Cost	$ 4,277,000	company BACT analysis	16.6	$/kW The single point unit capital cost factor shown for the "advanced" version of SOFA derived from Burns & McDonnell internal database and cost estimate for North Dakota lignite-fired cyclone boilers.
ASOFA Annualized Capital Cost	$ 403,719	calculated from TCC		
ASOFA Annual O&M Cost (not levelized)	$ 65,776	calculated from company BACT analysis minus the lost generation cost and adjusted to	100%	availability
ASOFA Total Annual Cost	$ 469,494	calculated		
LNB outlet = SCR Inlet NOx Concentration (lb/mmBtu)	0.51	from NDDH BACT analysis		
Required Controlled NOx Concentration (lb/mmBtu)	0.049	from NDDH BACT analysis		
Acceptable Ammonia Slip (ppm)	2.0	from OAQPS Cost Manual		
Fuel Volume Flow Rate (ft3/min/mmBtu/hr)	547	from OAQPS Cost Manual		
Fuel Sulfur Content	0.81%	from 2006 BACT analysis		
Fuel Ash Content	8.74%	from 2006 BACT analysis		
Number of SCR reactor chambers	1	from BACT analysis		
ASR	1.05	from OAQPS Cost Manual		
Stored Ammonia Concentration	29%	from OAQPS Cost Manual		
Reagent Molecular Weight (g/mole)	17.03	from OAQPS Cost Manual		
Reagent Density (lb/ft3 @ 60F)	56.0	from OAQPS Cost Manual		
Reagent Specific Volume (gal/ft3)	7.481	from OAQPS Cost Manual		
NOx Molecular Weight (g/mole)	46.01	from OAQPS Cost Manual		
Number of Days of Storage for Ammonia	14	assumed		
Pressure Drop for SCR Ductwork H2O")	3	from OAQPS Cost Manual		
Pressure Drop for each Catalyst Layer (H2O")	1	from OAQPS Cost Manual		
Temperature at SCR Inlet (degrees F)	563	from 2009 BACT analysis		
Equipment Life (years)	20	from OAQPS Cost Manual		
Annual Interest Rate	7%	from OAQPS Cost Manual		
Inflation Since 1998	1.35	CEPCI 2007/CEPCI 1998		
Catalyst Cost, Initial ($/ft3)	$ 85	calculated from	$ 3,000	/m^3 from PacifiCorp report
Catalyst Cost, Replacement ($/ft3)	$ 85	calculated from	$ 3,000	/m^3 from PacifiCorp report
Electrical Power Cost ($/kWh)	0.035	calculated from	$ 35.00	/MWhr from company report
29% Ammonia Solution Cost ($/lb)	$ 0.058	calculated from	$ 400.00	ton from PacifiCorp report
Operating Life of Catalyst (hours)	16,000	NDDH BACT report		
Natural gas unit cost ($/mcf)	$ 4.98	EIA 2010 price forecast		
Natural gas for reheat (mcf)	460,090	from BACT analysis		

MR Young Unit 1

Scenario	Upper Bound Heat Input (mmBtu/hr)	Upper Bound NOx Emission Rate (lb/mmBtu)	Upper Bound NOx Emission Rate (lb/hr)	Upper Bound Capacity Utilization	Upper Bound NOx Emission Rate (tpy)	NOx Emission Reduction (tpy)
Pre-BART	3,200	0.87	2,770	100%	12,135	
Post-ASOFA	3,200	0.51	1,642	100%	7,190	4,945
Pre-BART	3,200	0.87	2,770	95%	11,583	
Post-ASOFA	3,200	0.51	1,642	95%	6,863	4,720
Title V	3,200	0.86	2,752	100%	12,054	
Post-ASOFA	3,200	0.51	1,642	100%	7,190	4,864
Title V	3,200	0.86	2,752	96%	11,572	
Post-ASOFA	3,200	0.51	1,642	100%	7,190	4,381

LNB Control Efficiency = (Inlet Conc - Outlet Conc)/Inlet conc

(0.86 - 0.513)/ 0.86 = 40%

Boiler Calculations

2.3 $Q_B = HV\text{m-dot}_{fuel}$

QB = 6662 Btu/lb * 480336.24 lb/hr

QB = 3200 Btu/hr

2.7 $CF_{Plant} = \text{actual } m_{fuel}/\text{maximum } m_{fuel}$

CFPlant = 4.21E+09 lb/yr / 8760 hr/yr / 480336.24 lb/hr

CFPlant = 100%

2.8 $CF_{SCR} = t_{SCR}/365 \text{ days}$

CFSCR = 365 days/ 365 days

CFSCR = 100%

$CF_{Total} = CF_{Plant} \times CF_{SCR}$

CFTotal = 100% * 100%

CFTotal = 100%

2.12 $q_{fluegas} = q_{fuel}Q_B(460+T)/(460+700^{o}F)n_{SCR}$

qfluegas = 547 ft3/min/(mmBtu/hr)* 3200 mmBtu/hr*(460 + 563)/(460 + 700)/ 1

qfluegas = 1,543,672 acfm

2.9 $\eta_{NOx} = (NOx_{in} - NOx_{out}) / NOx_{in}$

ηNOx = (0.513 lb/mmBtu - 0.049 lb/mmBtu)/ 0.513 lb/mmBtu

ηNOx = 90%

Uncontrolled NOx emissions (tpy) **12,054**

Overall Control Efficiency = (Inlet Conc - Outlet Conc)/Inlet conc

(0.86 - 0.049)/ 0.86 = 94%

NOx removed = 11,367 tpy

Controlled NOx emissions (tpy) = 687 tpy

SCR Reactor Calculations

2.19 $Vol_{catalyst} = 2.81 \times Q_B \times \eta_{adj} \times Slip_{adj} \times NOx_{adj} \times S_{adj} \times T_{adj}/N_{SCR}$

Volcatalyst = 2.81 * 3200 = 8992

2.2 $\eta_{adj} = 0.2869 + (1.058 \times \eta)$

ηadj = 0.2869 +(1.058 * 0.90)
ηadj = 1.244

2.22 $Slip_{adj} = 1.2835 - (0.0567 \times Slip)$

Slipadj = 1.2835 - (0.057 * 2)
Slipadj = 1.170

2.21 $NOx_{adj} = 0.8524 + (0.3208 \times NOx_{in})$

NOxadj = 0.8524 + (0.321 * **0.51**)
NOxadj = 1.017

2.23 $S_{adj} = 0.9636 + (0.0455 \times S)$

Sadj = 0.9636 + (0.046 * 0.81)
Sadj = 1.000

2.24 $T_{adj} = 15.16 - (0.03937 \times T) + (2.74 \times 10^{-5} \times T^2)$

Tadj = 15.16 - (0.039 * 563) + 2.74E-05 * 316969
Tadj = 1.680

Volcatalyst = 22,365 ft3 each = 633.8 m3 each

2.25 $A_{catalyst} = q_{fluegas}/(16 \text{ ft/sec} \times 60 \text{ sec/min})$

Acatalyst = 1543672 /(16 * 60)
Acatalyst = 1608 ft2

2.26 $A_{SCR} = 1.15 \times A_{catalyst}$

ASCR = 1.15 * 1608
ASCR = 1849 ft2

2.27 $l = w = A_{SCR}^{1/2}$

l = w = 43.0 ft

2.28 $n_{layer} = Vol_{catalyst}/(h'_{layer} \times A_{catalyst})$

nlayer = 22365 /(3.1 * 1608)
nlayer = 4.0

2.29 $h_{layer} = [Vol_{catalyst}/(n_{layer} \times A_{catalyst})] + 1$

hlayer = 22365 /(3 * 1608) + 1
hlayer = 5.6

2.3 $n_{total} = n_{layer} + n_{empty}$

ntotal = 4 + 1
ntotal = 5

2.31 $h_{SCR} = n_{total}(c_1 + h_{layer}r) + c_2$

hSCR = 5 * (7 + 5.6) + 9
hSCR = 72 ft

Reagent Calculations

2.32 $\text{m-dot}_{reagent} = NOx_{in} Q_B ASR \eta_{NOx} M_{reagent} / M_{NOx}$

m-dotreagent =	**0.513** *	3200 *	1.05 *	**90%** *	17.03 /	46.01
m-dotreagent =	577 lb/hr					

2.33 $\text{m-dot}_{sol} = \text{m-dot}_{reagent} / C_{sol}$

m-dotsol =	577 /	0.29
m-dotsol =	1990 lb/hr	

2.34 $q_{sol} = (\text{m-dot}_{vol} / \rho_{sol}) V_{sol}$

qsol =	1990 *	7.481 /	56
qsol =	266 gph		

2.35 $\text{Tank Volume} = q_{sol} t$

Tank Volume =	266 *	14 *	24
Tank Volume =	89,317 gal		

Direct Capital Cost

2.36 $DC = Q_B[(\$3380/MMBtu/hr) + f(h_{SCR}) + f(NH_3rate) + f(new) + f(bypass)](3500/Q_B)^{0.35} + f(Vol_{catalyst})$

DC = 3200 (($ 3,380 +

2.37 $f(h_{SCR}) = \{[\$612/(ft\text{-}mmBtu/hr)]h_{SCR}\} - \$187.9/(mmBtu/hr)$

f(hSCR) = 6.12 * 72 - 187.9

f(hSCR) = $ 254 /mmBtu/hr

2.38 $f(NH_3rate) = [(\$411/lb/hr)(m\text{-}dot_{reagent}/Q_B)] - \$473/(mmBtu/hr)$

f(NH3rate) = 411 * 577 / 3200 - 47.3

f(NH3rate) = $ 27 /mmBtu/hr

2.39 f(new) = $0/(mmBtu/hr) for retrofit

f(new) = $ -

2.41 f(bypass) = $0/(mmBtu/hr) for no bypass

f(bypass) = $ 127 /mmBtu/hr

2.43 $f(Vol_{catalyst}) = Vol_{catalyst}CCinitial$

f(Volcatalyst) = 22365 * 85 * 1 chambers

f(Volcatalyst) = $ 1,901,371

DC = 3200 * ($ 3,380 + $ 254 + $ 27 + $ - + $ 127)*(3500 / 3200)^ 0.35 + $ 1,901,371

DC = $ 14,408,071

Extra Direct retrofit cost factor = 1.5

Inflation Adjustment = 1.35

DC = $ 29,176,343

Indirect Capital Costs

							Cost/DCC
Total Direct Capital Costs, A						$ 29,176,343	
Indirect Installation Costs							
General Facilities				0.05 A		$1,458,817	
Engineering and Home Office Fees				0.10 A		$2,917,634	
Process Contingencies				0.05 A		$1,458,817	
Total Indirect Installation Costs, B	Retrofit factor =	1.5	*	0.20 A =	0.30 A =	$8,752,903	30%
Project Contingency, C =	Retrofit factor =	1.5	*	0.15 (A+B) =	0.225 (A+B) =	$8,534,080	29%
Total Plant Cost D =					A+B+C	$46,463,327	159%
Allowance for Funds During Construction, E =				0		$0	
Royalty Allowance, F =				0		$0	
Preproduction Cost, G =				0.02 (D+E)		$929,267	
Inventory Capital, H =							
Initial Catalyst and Chemicals, I =	0.058 /lb *	1990 lb/r *		24 hr/day *	14 days =	$38,778	
Total Capital Investment TCI = D+G+H					+D+E+F+G+H+I	**$47,431,372**	163%
					Cost/kW =	$185	
Total Capital Investment TCI including ASOFA =						$51,708,372	
					Cost/kW =	$201	

Indirect Capital Costs

Item	Factor			Calculation		Manual Cost	Manual Cost/DCC	Minnkota Cost	Minnkota Cost/DCC
Total Direct Capital Costs, A						$ 123,201,171		$123,201,171	
Indirect Installation Costs									
General Facilities			0.05 A			$6,160,059			
Engineering and Home Office Fees			0.10 A			$12,320,117			
Process Contingencies			0.05 A			$6,160,059			
Total Indirect Installation Costs, B	Retrofit factor =	1.0 *	0.20 A =		0.20 A =	**$24,640,234**	20%	$ 45,332,315	37%
Project Contingency, C =	Retrofit factor =	1.0 *	0.15 (A+B) =		0.15 (A+B) =	$22,176,211	18%	$ 19,529,462	16%
Total Plant Cost D =				A+B+C		**$170,017,616**	138%	$188,062,948	153%
Allowance for Funds During Construction, E =				0		$0		$ 27,278,000	
Royalty Allowance, F =				0		$0			
Preproduction Cost, G =				0.02 (D+E)		$3,400,352			
Inventory Capital, H =									
Initial Catalyst and Chemical	0.058 /lb *	1990 lb/r *	24 hr/day *		14 days =	$38,778			
Escalation								$ 42,013,593	
NG pipeline						$ 6,750,000		$ 6,750,000	
Owner's costs								$ 26,204,034	
Total Capital Investment TCI = D+G+H				+D+E+F+G+H+I		$ 180,206,747	146%	$290,308,575	236%
				Cost/kW =		$701		$609	
Total Capital Investment TCI including ASOFA =						$184,483,747		$300,316,575	
				Cost/kW =		$718		$630	

Annual Costs

2.45 DAC = Annual Maintenance Cost + Annual Reagent Cost + Annual Electricity Cost + Annual Water Cost + Annual Catalyst Cost

2.46 Annual Maintenance Cost = 0.015 TCI

Annual Maintenance Cost = 0.015 * $ **47,431,372**
Annual Maintenance Cost = $ 711,471

2.47 Annual Reagent Cost = $q_{reagent}Cost_{reagent}t_{op}$

2.47a $t_{op} = CF_{total}8760hr/yr$

top = 100% * 8760
top = 8760
Annual Reagent Cost = 1990 * 8760 * 0.058
Annual Reagent Cost = $ 1,011,006

2.49 Annual Electricity Cost = Power $(Cost_{elect})t_{op}$

2.48 Power = $0.105Q_B[NOx_{in}\eta NOx + 0.5(\Delta P_{duct} + n_{total}\Delta P_{catalyst})]$

Power = 0.105 * 3200 *(**0.513** * 90% + 0.5 *(3 + 5 * 1))
Power = 1500 kW
Annual Electricity Cost = 1500 * 8760 * 0.035
Annual Electricity Cost = $ 459,871

2.51 Annual Catalyst Replacement Cost = (Catalyst Replacement Cost)FWF

2.5 Catalyst Replacement Cost = $n_{SCR}Vol_{catalyst}CC_{replace}/R_{layer}$

Catalyst Replacement Cost = 1 * 22365 * 85.01581521 / 1
Catalyst Replacement Cost = $ 1,901,371

2.52 $FWF = i\{1/[(1+i)^Y-1]\}$

2.53 $Y = h_{catalyst}/h_{year}$

Y = 16000 /(100% * 8760)
Y = 2
FWF = 0.07 *(1 /(1 + 0.07)^ 2 - 1)
FWF = 0.48
Annual Catalyst Cost = $ 918,537

Annual natural gas Cost = mcf/hr * 8,760 hr/y * $4.98 /mcf
Annual natural gas Cost = $ -

DAC = $ **3,100,884**

2.55 $CRF = i(1+i)^n/[(1+i)^n-1]$

CRF = 0.07 *(1 + 0.07)^ 20 /((1 + 0.07)^ 20 - 1)
CRF = 0.0944

Indirect Annual Cost = CFR * TCI
Indirect Annual Cost = 0.0944 * $ **47,431,372**
Indirect Annual Cost = $ 4,477,186

2.56 Total Annual Cost = Direct Annual Cost + Indirect Annual Cost

Total Annual Cost = $ 3,100,884 + 4,477,186
Total Annual Cost = $ **7,578,070** + $ 469,494 = $ **8,047,565**

2.57 NOx Removed = $NOx_{in}\eta_{NOx}Q_Bt_{op}$

NOx Removed = **0.513** * 90% * 3200 * 8760 / 2000
NOx Removed = 6,503

Total NOx Removed = 11,367

2.58 Cost effectiveness = TAC/NOx removed

SCR Cost effectiveness = $ **1,165**
Total Cost effectiveness = $ 708

Annual Costs

2.45 DAC = Annual Maintenance Cost + Annual Reagent Cost + Annual Electricity Cost + Annual Water Cost + Annual Catalyst Cost

2.46 Annual Maintenance Cost = 0.015 TCI

Annual Maintenance Cost = 0.015 * **$ 180,206,747**
Annual Maintenance Cost = $ 2,703,101

2.47 Annual Reagent Cost = $q_{reagent}Cost_{reagent}t_{op}$

2.47a $t_{op} = CF_{total}8760hr/yr$

top = 100% * 8760
top = 8760
Annual Reagent Cost = 1990 * 8760 * 0.058
Annual Reagent Cost = $ 1,011,006

2.49 Annual Electricity Cost = Power $(Cost_{elect})t_{op}$

2.48 Power = $0.105Q_B[NOx_{in}\eta NOx + 0.5(\Delta P_{duct} + n_{total}\Delta P_{catalyst})]$

Power = 0.105 * 3200 *(**0.513** * 90% + 0.5 * (3 + 5 * 1))
Power = 1500 kW
Annual Electricity Cost = 1500 * 8760 * 0.035
Annual Electricity Cost = $ **459,871**

2.51 Annual Catalyst Replacement Cost = (Catalyst Replacement Cost)FWF

2.5 Catalyst Replacement Cost = $n_{SCR}Vol_{catalyst}CC_{replace}/R_{layer}$

Catalyst Replacement Cost = 1 * 22365 * 85.01581521 / 1
Catalyst Replacement Cost = $ 1,901,371

2.52 $FWF = i\{1/[(1+i)^Y-1]\}$

2.53 $Y = h_{catalyst}/h_{year}$

Y = 16000 /(100% * 8760)
Y = 2
FWF = 0.07 *(1 /(1 + 0.07)^ 2 - 1)
FWF = 0.48
Annual Catalyst Cost = $ **918,537**

Annual natural gas Cost = 460,090 mcf/yr * $4.98 /mcf
Annual natural gas Cost = $ **2,291,248**

DAC = $ **7,383,763**

2.55 $CRF = i(1+i)^n/[(1+i)^n-1]$

CRF = 0.07 *(1 + 0.07)^ 20 /((1 + 0.07)^ 20 - 1)
CRF = 0.0944

Indirect Annual Cost = CFR * TCI
Indirect Annual Cost = 0.0944 * **$ 180,206,747**
Indirect Annual Cost = $ **17,010,242**

2.56 Total Annual Cost = Direct Annual Cost + Indirect Annual Cost

Total Annual Cost = $ 7,383,763 + 17,010,242
Total Annual Cost = $ **24,394,005** + $ 469,494 = **$ 24,863,500**

2.57 NOx Removed = $NOx_{in}\eta_{NOx}Q_Bt_{op}$

NOx Removed = **0.513** * 90% * 3200 * 8760 / 2000
NOx Removed = 6,503

Total NOx Removed = 11,367

2.58 Cost effectiveness = TAC/NOx removed

SCR Cost effectiveness = $ 3,751
Total Cost effectiveness = $ 2,187

Operating company	**Basin Electric Power**		
Facility	**Milton R. Young**		
State	**ND**		
Contact	**Tom Bachman**	**tbachman@nd.gov**	**(701) 328-5188**

# of Class I Areas evaluated/within 300 km		2	
Unit		#1	
Boiler Type		cyclone	ND DOH report
Fuel		ND lignite	ND DOH report
Rating (MW Gross)		257	NDDH BART report
Presumptive BART limit (lb/mmBtu)		**0.10**	**cyclone > 200 MW firing lignite**
Rating (mmBtu/hr)		3,200	mmBtu/hr from NDDH BART report
Current Emissions (tpy)		12,054	calculated from NDDH Title V permit
Current Emisison Rate (lb/mmBtu)		0.86	calculated from NDDH Title V permit
ASOFA			
Control Efficiency		40%	calculated
New Emisison Rate (lb/mmBtu)		0.513	from NDDH BACT analysis
New Emissions (tpy)		7,190	calculated
Emissions Reduction (tpy)		4,864	calculated
Capital Cost	$	4,277,000	company BACT analysis
Capital Cost ($/kW)	$	17	calculated
O&M Cost	$	65,776	calculated from company BACT analysis minus the lost generation cost and adjusted to 100%
Total Annual Cost	$	469,494	calculated
Cost-Effectiveness ($/ton)	$	97	calculated
SCR			
Control Efficiency		90%	calculated
New Emisison Rate (lb/mmBtu)		0.049	from NDDH BACT analysis
New Emissions (tpy)		687	calculated
Emissions Reduction (tpy)		6,503	NPS based upon OAQPS Control Cost Manual
Capital Cost	$	180,206,747	calculated
Capital Cost ($/kW)	$	701	calculated
O&M Cost	$	7,383,763	NPS based upon OAQPS Control Cost Manual
Total Annual Cost	$	24,394,005	NPS based upon OAQPS Control Cost Manual
Incremental Cost-Effectiveness ($/ton)	$	3,751	NPS based upon OAQPS Control Cost Manual
ASOFA+SCR			
Control Efficiency		94%	calculated
New Emisison Rate (lb/mmBtu)		0.049	from NDDH BACT analysis
New Emissions (tpy)		687	calculated
Emissions Reduction (tpy)		11,367	calculated
Capital Cost	$	184,483,747	calculated
Capital Cost ($/kW)	$	718	calculated
O&M Cost	$	7,449,539	calculated
Total Annual Cost	$	24,863,500	calculated
Cost-Effectiveness ($/ton)	$	2,187	calculated
NPS			
Effective Reduction from Current		94%	calculated
Effective BART Limit (tpy)		**687**	calculated
Effective Reduction from Current (tpy)		11,367	calculated

Appendix B.
Milton R. Young Unit #2
OAQPS Control Cost Manual Section 4.2, SCR, p2-50

Given/Assumptions

New or Retrofit?	Retrofit				
Extra Direct retrofit cost	1.5	NPS estimate			
Extra Indirect retrofit cost factor	2	NPS estimate			
Generation capacity (MW)	477	NDDH BART report			
SCR bypass included?	Yes	from BACT analysis			
Fuel High Heating Value (Btu/lb)	6,662	from 2006 BACT analysis			
Maximum Fuel Consumption Rate (lb/hr)	9.5E+05	calculated from		6,300	mmBtu/hr from NDDH BART report
Average Annual Fuel Consumption (lb)	8.26E+09	calculated			
Number of SCR Operating Days	365	assumed			
Plant Capacity Factor	100%	from NDDH Title V permit			
Uncontrolled NOx Concentration (lb/mmBtu)	0.86	calculated from NDDH Title V permit			
Uncontrolled NOx Emissions (tpy)	23,731	calculated from NDDH Title V permit			
ASOFA Total Capital Cost	$10,009,000	company BACT analysis		21	$/kW The single point unit capital cost factor shown for the "advanced" version of SOFA derived from Burns & McDonnell internal database and cost estimate for North Dakota lignite-fired cyclone boilers.
ASOFA Annualized Capital Cost	$ 944,684	calculated from TCC			
ASOFA Annual O&M Cost (not levelized)	$ 159,744	calculated from company BACT analysis minus the lost generation cost and adjusted to		100%	availability
ASOFA Total Annual Cost	$ 1,104,429	calculated			
LNB outlet = SCR inlet NOx Concentration (lb/mmBtu)	0.489	from NDDH BACT analysis			
Required Controlled NOx Concentration (lb/mmBtu)	0.049	from NDDH BACT analysis			
Acceptable Ammonia Slip (ppm)	2.0	from OAQPS Cost Manual			
Fuel Volume Flow Rate (ft3/min/mmBtu/hr)	547	from OAQPS Cost Manual			
Fuel Sulfur Content	0.81%	from 2006 BACT analysis			
Fuel Ash Content	8.74%	from 2006 BACT analysis			
Number of SCR reactor chambers	2	from BACT analysis			
ASR	1.05	from OAQPS Cost Manual			
Stored Ammonia Concentration	29%	from OAQPS Cost Manual			
Reagent Molecular Weight (g/mole)	17.03	from OAQPS Cost Manual			
Reagent Density (lb/ft3 @ 60F)	56.0	from OAQPS Cost Manual			
Reagent Specific Volume (gal/ft3)	7.481	from OAQPS Cost Manual			
NOx Molecular Weight (g/mole)	46.01	from OAQPS Cost Manual			
Number of Days of Storage for Ammonia	14	assumed			
Pressure Drop for SCR Ductwork H2O")	3	from OAQPS Cost Manual			
Pressure Drop for each Catalyst Layer (H2O")	1	from OAQPS Cost Manual			
Temperature at SCR Inlet (degrees F)	563	from 2009 BACT analysis			
Equipment Life (years)	20	from OAQPS Cost Manual			
Annual Interest Rate	7%	from OAQPS Cost Manual			
Inflation Since 1998	1.35	CEPCI 2007/CEPCI 1998			
Catalyst Cost, Initial ($/ft3)	$ 85	calculated from	$	3,000	/m^3 from PacifiCorp report
Catalyst Cost, Replacement ($/ft3)	$ 85	calculated from	$	3,000	/m^3 from PacifiCorp report
Electrical Power Cost ($/kWh)	0.035	calculated from	$	35.00	/MWhr from company report
29% Ammonia Solution Cost ($/lb)	$ 0.058	from OAQPS Cost Manual	$	400.00	ton from PacifiCorp report
Operating Life of Catalyst (hours)	16,000	NDDH BACT report			
Natural gas unit cost ($/mcf)	$ 4.98	EIA 2010 price forecast			
Natural gas for reheat (mcf)	754,563	from BACT analysis			

MR Young Unit 2

Scenario	Upper Bound Heat Input (mmBtu/hr)	Upper Bound NOx Emission Rate (lb/mmBtu)	Upper Bound NOx Emission Rate (lb/hr)	Upper Bound Capacity Utilization	Upper Bound NOx Emission Rate (tpy)	NOx Emission Reduction (tpy)
Pre-BART	6,300	0.86	5,393	100%	23,620	
Post-ASOFA	6,300	0.49	3,081	100%	13,493	10,127
Pre-BART	6,300	0.86	5,393	95%	22,546	
Post-ASOFA	6,300	0.49	3,081	95%	12,880	9,666
Title V	6,300	0.86	5,418	100%	23,731	
Post-ASOFA	6,300	0.49	3,081	100%	13,493	10,237
Title V	6,300	0.86	5,418	95%	22,652	
Post-ASOFA	6,300	0.49	3,081	95%	12,880	9,772

LNB Control Efficiency = (Inlet Conc - Outlet Conc)/Inlet conc

(0.86 - 0.489)/ 0.86 = 43%

Boiler Calculations

2.3 $Q_B = HV m\text{-}dot_{fuel}$

QB = 6662 Btu/lb * 945661.96 lb/hr

QB = 6300 Btu/hr

2.7 $CF_{Plant} = \text{actual } m_{fuel}/\text{maximum } m_{fuel}$

CFPlant = 8.28E+09 lb/yr / 8760 hr/yr / 945661.96 lb/hr

CFPlant = 100%

2.8 $CF_{SCR} = t_{SCR}/365 \text{ days}$

CFSCR = 365 days/ 365 days

CFSCR = 100%

$CF_{Total} = CF_{Plant} \times CF_{SCR}$

CFTotal = 100% * 100%

CFTotal = 100%

2.12 $q_{fluegas} = q_{fuel} Q_B (460+T)/(460+700^{o}F) n_{SCR}$

qfluegas = 547 ft3/min/(mmBtu/hr)* 6300 mmBtu/hr*(460 + 563)/(460 + 700)/ 2

qfluegas = 6,078,207 acfm

2.9 $\eta_{NOx} = (NOx_{in} - NOx_{out}) / NOx_{in}$

ηNOx = (0.489 lb/mmBtu - 0.049 lb/mmBtu)/ 0.489 lb/mmBtu

ηNOx = 90%

Uncontrolled NOx emissions (tpy) **23,731**

Overall Control Efficiency = (Inlet Conc - Outlet Conc)/Inlet conc

(0.86 - 0.049)/ 0.86 = 94%

NOx removed = 22,379 tpy

Controlled NOx emissions (tpy) = 1,352 tpy

SCR Reactor Calculations

2.19 $Vol_{catalyst} = 2.81 \times Q_B \times \eta_{adj} \times Slip_{adj} \times NOx_{adj} \times S_{adj} \times T_{adj}/N_{SCR}$

Volcatalyst = 2.81 * 6300 = 17703

2.2 $\eta_{adj} = 0.2869 + (1.058 \times \eta)$

ηadj = 0.2869 +(1.058 * 0.90)
ηadj = 1.239

2.22 $Slip_{adj} = 1.2835 - (0.0567 \times Slip)$

Slipadj = 1.2835 - (0.057 * 2)
Slipadj = 1.170

2.21 $NOx_{adj} = 0.8524 + (0.3208 \times NOx_{in})$

NOxadj = 0.8524 + (0.321 * **0.49**)
NOxadj = 1.009

2.23 $S_{adj} = 0.9636 + (0.0455 \times S)$

Sadj = 0.9636 + (0.046 * 0.81)
Sadj = 1.000

2.24 $T_{adj} = 15.16 - (0.03937 \times T) + (2.74 \times 10^{-5} \times T^2)$

Tadj = 15.16 - (0.039 * 563) + 2.74E-05 * 316969
Tadj = 1.680

Volcatalyst = 21,762 ft3 each = **616.7 m3 each**

2.25 $A_{catalyst} = q_{fluegas}/(16 \text{ ft/sec} \times 60 \text{ sec/min})$

Acatalyst = 6078207 /(16 * 60)
Acatalyst = 6331 ft2

2.26 $A_{SCR} = 1.15 \times A_{catalyst}$

ASCR = 1.15 * 6331
ASCR = 7281 ft2

2.27 $l = w = A_{SCR}^{1/2}$

l = w = 85.3 ft

2.28 $n_{layer} = Vol_{catalyst}/(h'_{layer} \times A_{catalyst})$

nlayer = 21762 /(3.1 * 6331)
nlayer = 1.0

2.29 $h_{layer} = [Vol_{catalyst}/(n_{layer} \times A_{catalyst})] + 1$

hlayer = 21762 /(3 * 6331) + 1
hlayer = 2.1

2.3 $n_{total} = n_{layer} + n_{empty}$

ntotal = 1 + 1
ntotal = 2

2.31 $h_{SCR} = n_{total}(c_1 + h_{layer}r) + c_2$

hSCR = 2 * (7 + 2.1) + 9
hSCR = 27 ft

Reagent Calculations

2.32 $\text{m-dot}_{reagent} = NOx_{in} Q_B ASR \eta_{NOx} M_{reagent} / M_{NOx}$

m-dotreagent =	**0.489** *	6300 *	1.05 *	**90%** *	17.03 /	46.01
m-dotreagent =	1077 lb/hr					

2.33 $\text{m-dot}_{sol} = \text{m-dot}_{reagent} / C_{sol}$

m-dotsol =	1077 /	0.29
m-dotsol =	3715 lb/hr	

2.34 $q_{sol} = (\text{m-dot}_{vol} / \rho_{sol}) V_{sol}$

qsol =	3715 *	7.481 /	56
qsol =	496 gph		

2.35 Tank Volume = $q_{sol} t$

Tank Volume =	496 *	14 *	24
Tank Volume =	166,747 gal		

Direct Capital Cost

2.36 $DC = Q_B[(\$3380/MMBtu/hr) + f(h_{SCR}) + f(NH_3rate) + f(new) + f(bypass)](3500/Q_B)^{0.35} + f(Vol_{catalyst})$

DC = 6300 (($ 3,380 +

2.37 $f(h_{SCR}) = \{[\$612/(ft\text{-}mmBtu/hr)]h_{SCR}\} - \$187.9/(mmBtu/hr)$

f(hSCR) = 6.12 * 27 - 187.9

f(hSCR) = $ (21) /mmBtu/hr

2.38 $f(NH_3rate) = [(\$411/lb/hr)(m\text{-}dot_{reagent}/Q_B)] - \$473/(mmBtu/hr)$

f(NH3rate) = 411 * 1077 / 6300 - 47.3

f(NH3rate) = $ 23 /mmBtu/hr

2.39 f(new) = $0/(mmBtu/hr) for retrofit

f(new) = $ -

2.41 f(bypass) = $0/(mmBtu/hr) for no bypass

f(bypass) = $ 127 /mmBtu/hr

2.43 $f(Vol_{catalyst}) = Vol_{catalyst}CCinitial$

f(Volcatalyst) = 21762 * 85 * 2 chambers

f(Volcatalyst) = $ 3,700,172

DC = 6300 * ($ 3,380 + $ (21) + $ 23 + $ - + $ 127)*(3500 / 6300)^ 0.35 + $ 3,700,172

DC = $ 21,696,819

Extra Direct retrofit cost factor = 1.5

Inflation Adjustment = 1.35

DC = $ 43,936,059

Indirect Capital Costs

								Cost/DCC
Total Direct Capital Costs, A							$ 43,936,059	
Indirect Installation Costs								
General Facilities					0.05 A		$2,196,803	
Engineering and Home Office Fees					0.10 A		$4,393,606	
Process Contingencies					0.05 A		$2,196,803	
Total Indirect Installation Costs, B	Retrofit factor =		2.0	*	0.20 A =	0.40 A =	$17,574,424	40%
Project Contingency, C =	Retrofit factor =		2.0	*	0.15 (A+B) =	0.3 (A+B) =	$18,453,145	42%
Total Plant Cost D =						A+B+C	$79,963,627	182%
Allowance for Funds During Construction, E =					0		$0	
Royalty Allowance, F =					0		$0	
Preproduction Cost, G =					0.02 (D+E)		$1,599,273	
Inventory Capital, H =								
Initial Catalyst and Chemicals, I =	0.058 /lb *	3715 lb/r *			24 hr/day *	14 days =	$72,396	
Total Capital Investment TCI = D+G+H						+D+E+F+G+H+I	$81,635,296	186%
						Cost/kW =	$171	
Total Capital Investment TCI including LNB + ASOFA =							$91,643,296	
						Cost/kW =	$192	

Indirect Capital Costs						Manual Cost	Manual Cost/DCC	Minnkota Cost	Cost/DCC
Total Direct Capital Costs, A						$ 189,620,329		$189,620,329	
Indirect Installation Costs									
General Facilities				0.05 A		$9,481,016			
Engineering and Home Office Fees				0.10 A		$18,962,033			
Process Contingencies				0.05 A		$9,481,016			
Total Indirect Installation Costs, B	Retrofit factor =	1.0	*	0.20 A =	0.20 A =	$37,924,066	20%	$ 70,460,562	37%
Project Contingency, C =	Retrofit factor =	1.0	*	0.15 (A+B) =	0.15 (A+B) =	$34,131,659	18%	$ 29,593,180	16%
Total Plant Cost D =					A+B+C	$261,676,054	138%	$289,674,071	153%
Allowance for Funds During Construction, E =				0		$0		$ 41,228,900	
Royalty Allowance, F =				0		$0			
Preproduction Cost, G =				0.02 (D+E)		$5,233,521			
Inventory Capital, H =									
Initial Catalyst and Chemicals, I =	0.058 /lb *	### lb/r *		24 hr/day *	14 days =	$72,396			
Escalation								$ 55,436,089	
NG pipeline						$ 6,750,000		$ 6,750,000	
Owner's costs								$ 33,248,637	
Total Capital Investment TCI = D+G+H					+D+E+F+G+H+I	$266,981,971	141%	$426,337,697	225%
					Cost/kW =	$560		$894	
Total Capital Investment TCI including LNB + ASOFA =						$276,989,971		$436,345,697	
					Cost/kW =	$581		$915	

Annual Costs

2.45 DAC = Annual Maintenance Cost + Annual Reagent Cost + Annual Electricity Cost + Annual Water Cost + Annual Catalyst Cost

2.46 Annual Maintenance Cost = 0.015 TCI

Annual Maintenance Cost = 0.015 * $ **81,635,296**
Annual Maintenance Cost = $ 1,224,529

2.47 Annual Reagent Cost = $q_{reagent}Cost_{reagent}t_{op}$

2.47a $t_{op} = CF_{total}8760hr/yr$

top = 100% * 8760
top = 8760
Annual Reagent Cost = 3715 * 8760 * 0.058
Annual Reagent Cost = $ 1,887,466

2.49 Annual Electricity Cost = Power $(Cost_{elect})t_{op}$

2.48 Power = $0.105Q_B[NOx_{in}\eta NOx + 0.5(\Delta P_{duct} + n_{total}\Delta P_{catalyst})]$

Power = 0.105 * 6300 *(**0.489** * 90% + 0.5 * (3 + 2 * 1))
Power = 1945 kW
Annual Electricity Cost = 1945 * 8760 * 0.035
Annual Electricity Cost = $ 596,279

2.51 Annual Catalyst Replacement Cost = (Catalyst Replacement Cost)FWF

2.5 Catalyst Replacement Cost = $n_{SCR}Vol_{catalyst}CC_{replace}/R_{layer}$

Catalyst Replacement Cost = 2 * 21762 * 85.01581521 / 1
Catalyst Replacement Cost = $ 3,700,172

2.52 FWF = $i\{1/[(1+i)^Y-1]\}$

2.53 Y = $h_{catalyst}/h_{year}$

Y = 16000 /(100% * 8760)
Y = 2
FWF = 0.07 *(1 /(1 + 0.07)^ 2 - 1)
FWF = 0.48
Annual Catalyst Cost = $ 1,787,523

Annual natural gas Cost = 754,563 mcf/yr * $4.98 /mcf
Annual natural gas Cost = $ 3,757,724

DAC = **$ 9,253,520**

2.55 CRF = $i(1+i)^n/[(1+i)^n-1]$

CRF = 0.07 *(1 + 0.07)^ 20 /((1 + 0.07)^ 20 - 1)
CRF = 0.0944

Indirect Annual Cost = CFR * TCI
Indirect Annual Cost = 0.0944 * $ **81,635,296**
Indirect Annual Cost = $ 7,705,794

2.56 Total Annual Cost = Direct Annual Cost + Indirect Annual Cost

Total Annual Cost = $ 9,253,520 + 7,705,794
Total Annual Cost = **$ 16,959,315** + $ 1,104,429 = $ 18,063,743

2.57 NOx Removed = $NOx_{in}\eta_{NOx}Q_Bt_{op}$

NOx Removed = **0.489** * 90% * 6300 * 8760 / 2000
NOx Removed = 12,141

Total NOx Removed = 22,379

2.58 Cost effectiveness = TAC/NOx removed

SCR Cost effectiveness = **$** 1,397
Total Cost effectiveness = **$** 807

Annual Costs

2.45 DAC = Annual Maintenance Cost + Annual Reagent Cost + Annual Electricity Cost + Annual Water Cost + Annual Catalyst Cost

2.46 Annual Maintenance Cost = 0.015 TCI

Annual Maintenance Cost = 0.015 * **$ 266,981,971**
Annual Maintenance Cost = $ 4,004,730

2.47 Annual Reagent Cost = $q_{reagent}Cost_{reagent}t_{op}$

2.47a $t_{op} = CF_{total}8760hr/yr$

top = 100% * 8760
top = 8760
Annual Reagent Cost = 3715 * 8760 * 0.058
Annual Reagent Cost = $ **1,887,466**

2.49 Annual Electricity Cost = Power $(Cost_{elect})t_{op}$

2.48 Power = $0.105Q_B[NOx_{in}\eta NOx + 0.5(\Delta P_{duct} + n_{total}\Delta P_{catalyst})]$

Power = 0.105 * 6300 *(**0.489** * 90% + 0.5 * (3 + 2 * 1))
Power = 1945 kW
Annual Electricity Cost = 1945 * 8760 * 0.035
Annual Electricity Cost = $ **596,279**

2.51 Annual Catalyst Replacement Cost = (Catalyst Replacement Cost)FWF

2.5 Catalyst Replacement Cost = $n_{SCR}Vol_{catalyst}CC_{replace}/R_{layer}$

Catalyst Replacement Cost = 2 * 21762 * 85.01581521 / 1
Catalyst Replacement Cost = $ 3,700,172

2.52 FWF = $i\{1/[(1+i)^Y-1]\}$

2.53 Y = $h_{catalyst}/h_{year}$

Y = 16000 /(100% * 8760)
Y = 2
FWF = 0.07 *(1 /(1 + 0.07)^ 2 - 1)
FWF = 0.48
Annual Catalyst Cost = $ **1,787,523**

Annual natural gas Cost = 754,563 mcf/yr * $4.98 /mcf
Annual natural gas Cost = $ 3,757,724

DAC = **$ 12,033,720**

2.55 CRF = $i(1+i)^n/[(1+i)^n-1]$

CRF = 0.07 *(1 + 0.07)^ 20 /((1 + 0.07)^ 20 - 1)
CRF = 0.0944

Indirect Annual Cost = CFR * TCI
Indirect Annual Cost = 0.0944 * **$ 266,981,971**
Indirect Annual Cost = $ 25,201,209

2.56 Total Annual Cost = Direct Annual Cost + Indirect Annual Cost

Total Annual Cost = $ 12,033,720 + 25,201,209
Total Annual Cost = **$ 37,234,930** + $ 1,104,429 = $ 38,339,358

2.57 NOx Removed = $NOx_{in}\eta_{NOx}Q_Bt_{op}$

NOx Removed = **0.489** * 90% * 6300 * 8760 / 2000
NOx Removed = 12,141

Total NOx Removed = 22,379

2.58 Cost effectiveness = TAC/NOx removed

SCR Cost effectiveness = $ 3,067
Total Cost effectiveness = $ 1,713

Operating company	**Basin Electric Power**		
Facility	**Milton R. Young**		
State	**ND**		
Contact	**Tom Bachman**		**(701) 328-5188**
# of Class I Areas evaluated/within 300 km		2	
Unit		#2	
Boiler Type		cyclone	ND DOH report
Fuel		ND lignite & PRB	ND DOH report
Rating (MW Gross)		477	ND DOH report
Presumptive BART limit (lb/mmBtu)		**0.10**	**cyclone > 200 MW firing lignite**
Rating (mmBtu/hr)		6,300	mmBtu/hr from NDDH BART report
Current Emissions (tpy)		23,731	calculated from NDDH Title V permit
Current Emisison Rate (lb/mmBtu)		0.86	calculated from NDDH Title V permit
ASOFA			
Control Efficiency		43%	calculated
New Emisison Rate (lb/mmBtu)		0.489	from NDDH BACT analysis
New Emissions (tpy)		13,493	calculated
Emissions Reduction (tpy)		10,237	calculated
Capital Cost	$	10,008,000	company BACT analysis
Capital Cost ($/kW)	$	21	calculated
O&M Cost	$	159,744	calculated from company BACT analysis minus the lost generation cost and adjusted to 100%
Total Annual Cost	$	1,104,429	calculated
Cost-Effectiveness ($/ton)	$	108	calculated
SCR			
Control Efficiency		90%	calculated
New Emisison Rate (lb/mmBtu)		0.049	from NDDH BACT analysis
New Emissions (tpy)		1,352	calculated
Emissions Reduction (tpy)		12,141	NPS based upon OAQPS Control Cost Manual
Capital Cost	$	266,981,971	calculated
Capital Cost ($/kW)	$	560	calculated
O&M Cost	$	12,033,720	NPS based upon OAQPS Control Cost Manual
Total Annual Cost	$	37,234,930	NPS based upon OAQPS Control Cost Manual
Incremental Cost-Effectiveness ($/ton)	$	3,067	NPS based upon OAQPS Control Cost Manual
ASOFA+SCR			
Control Efficiency		94%	calculated
New Emisison Rate (lb/mmBtu)		**0.049**	**lb/mmBtu (30-day rolling average)**
New Emissions (tpy)		1,352	calculated
Emissions Reduction (tpy)		22,379	NPS based upon OAQPS Control Cost Manual
Capital Cost	$	276,989,971	calculated
Capital Cost ($/kW)		581	calculated
O&M Cost	$	12,193,465	calculated
Total Annual Cost	$	38,339,358	calculated from company & ND DOH reports
Cost-Effectiveness ($/ton)	$	1,713	calculated
NPS			
Effective Reduction from Current		94%	calculated
Effective BART Limit (tpy)		**1,352**	calculated
Effective Reduction from Current (tpy)		22,379	calculated